UCID- 18991-86

CALIFORNIA ENERGY FLOW IN 1986

I. Y. Borg
C. K. Briggs

November 20, 1987

Lawrence Livermore National Laboratory

Work performed under the auspices of the U.S. Department of Energy by the Lawrence Livermore National Laboratory under Contract W-7405-Eng-48.

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

Price Code	Page Range
A01	Microfiche
Papercopy Prices	
A02	001-050
A03	051-100
A04	101-200
A05	201-300
A06	301-400
A07	401-500
A08	501-600
A09	601

CONTENTS

	Page
ABSTRACT	2
INTRODUCTION	3
CALIFORNIA ENERGY FLOW DIAGRAMS	3
CALIFORNIA'S ENERGY FLOW IN 1986 COMPARED TO 1985	4
OIL AND GAS PRODUCTION	11
NATURAL GAS SUPPLY	15
ELECTRIC POWER	16
Source of supply	16
Cogeneration and the impending power surplus	17
Nuclear power	19
Renewable sources of electricity	20
Geothermal power	20
Windpower	21
METHANOL AS AN ALTERNATIVE TRANSPORTATION FUEL	23
APPENDIX A	24
APPENDIX B	25
APPENDIX C	26
REFERENCES	27

ABSTRACT

Although California is the fourth largest oil producing state in the nation, 45% of the state's energy supply is from out-of-state sources. Imported oil and natural gas are the principal fuels used. The only coal used within state borders is a small amount of coking coal.

Total energy demand in California fell 1.5% in 1986 in part due to a mild winter that led to decreased heating requirements in the residential, commercial, and to a lesser extent, the industrial end-use sectors. The decline in industrial energy consumption paralleled the decline registered in the U.S. as a whole, but was more marked in California. As industrial activity was robust by all criteria, the decline relates to increased efficiencies as well as the increasing importance of service industries and other less energy intensive components in the sector. Consumption of fuels for transportation increased to an all time high; the growth in 1986 exceeded the estimated population increase over the same period.

Cogeneration and self-generation of electrical power increased substantially and continued to displace utility generated power which has posed problems for the utilities and regulatory agencies alike. Expected growth in both sources, as well as in alternative sources of power in the state, such as geothermal and windpower, promises to produce an electrical capacity surplus within a few years.

INTRODUCTION

For the past ten years energy flow diagrams for the State of California have been prepared from available data by members of the Lawrence Livermore National Laboratory.[1-6] They have proven to be useful tools in graphically expressing energy supply and use in the State as well as illustrating the difference between particular years and between the State and the US as a whole.

As far as is possible similar data sources have been used to prepare the diagrams from year to year and identical assumptions[2] concerning conversion efficiences have been made in order to minimize inconsistencies in the data and analyses. Sources of data used in this report are given in Appendix A and B; unavoidably the sources used over the 1976–1986 period have varied as some data bases are no longer available. In addition, we continue to see differences in specific data reported by different agencies for a given year. In particular, reported data on supply and usage in industrial/commercial/firm industrial/residential end-use categories have shown variability amongst the data gathering agencies, which bars detailed comparisons from year to year. Nonetheless, taken overall some generalizations can be made concerning gross trends and changes.

CALIFORNIA ENERGY FLOW DIAGRAMS

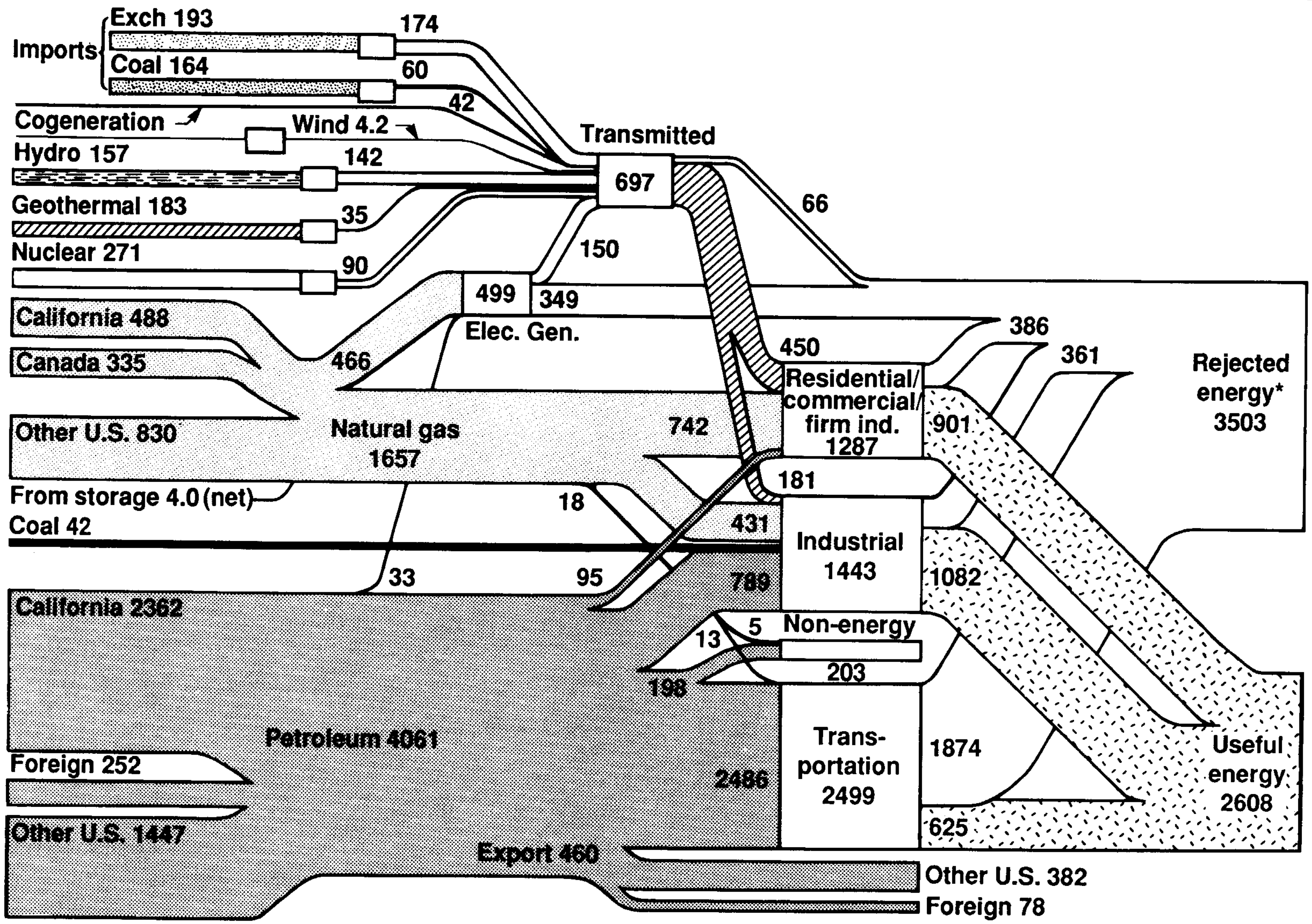
Energy flow diagrams for 1986 and 1985 are shown in Figures 1 and 2 respectively. The U.S. energy flow diagram for 1986 is shown for comparison in Figure 3. Energy sources are shown on the left, and energy consumption is shown on the right. Also shown on the right are estimates of conversion efficiencies in the end-use sector, which result in a division between useful and rejected energy. The latter consists primarily of heat losses but also includes other sorts of losses such as line losses during electrical transmission.

Inputs to total transmitted electricity such as nuclear, geothermal power, etc., are associated with estimated efficiencies of the conversion process to electricity. They vary from 90% in the case of hydroelectric power to 18% for geothermal energy. Assumptions concerning the conversion efficiencies are given in Appendix C, and their rationale can be found in Ref. 2. The box separating the energy source from the final electrical output represents the conversion process. In all cases the quantities associated with the electrical energy source are calculated based on assumed conversion efficiencies. While it is desirable to minimize the number of assumptions in preparing an energy flow diagram, it is also desirable to express as closely as possible the energy content of the fuels used during the year. In this way changes and improvements in overall fuel conversions that occur over the course of time by virtue of fuel switching and use of renewable sources such as windpower or solar energy have an expression in the total energy consumption for the year.

CALIFORNIA'S ENERGY FLOW IN 1986 COMPARED TO 1985

The total amount of energy consumed in the state fell approximately 1.5% in 1986. A large part of the decline can be attributed to a mild winter as judged by annual heating degree days (Table 1) that led to an approximate ten percent decrease in consumption in the residential and commercial and to a lesser extent the industrial end-use sectors. This was partially countered by an increase in the use of transportation fuels (Table 2) which exceeded the estimated 2.4% increase in population.[7] By July 1986 the California Department of Finance reported there were twenty seven million people living in the state, nine million more than in New York, the next most populous state. There was an impressive drop in industrial energy usage in the state. In the nation as a whole there was also a decrease, albeit not so large as in California. As the national GNP increased over the same time span, the explanation may lie in increased energy efficiency and the change in the make up of the GNP such that it reflects increased contribution from service industries whose energy use is less than that of industrial end use sector.

CALIFORNIA ENERGY FLOW - 1986
TOTAL CONSUMPTION 6300 × 10^{12}Btu

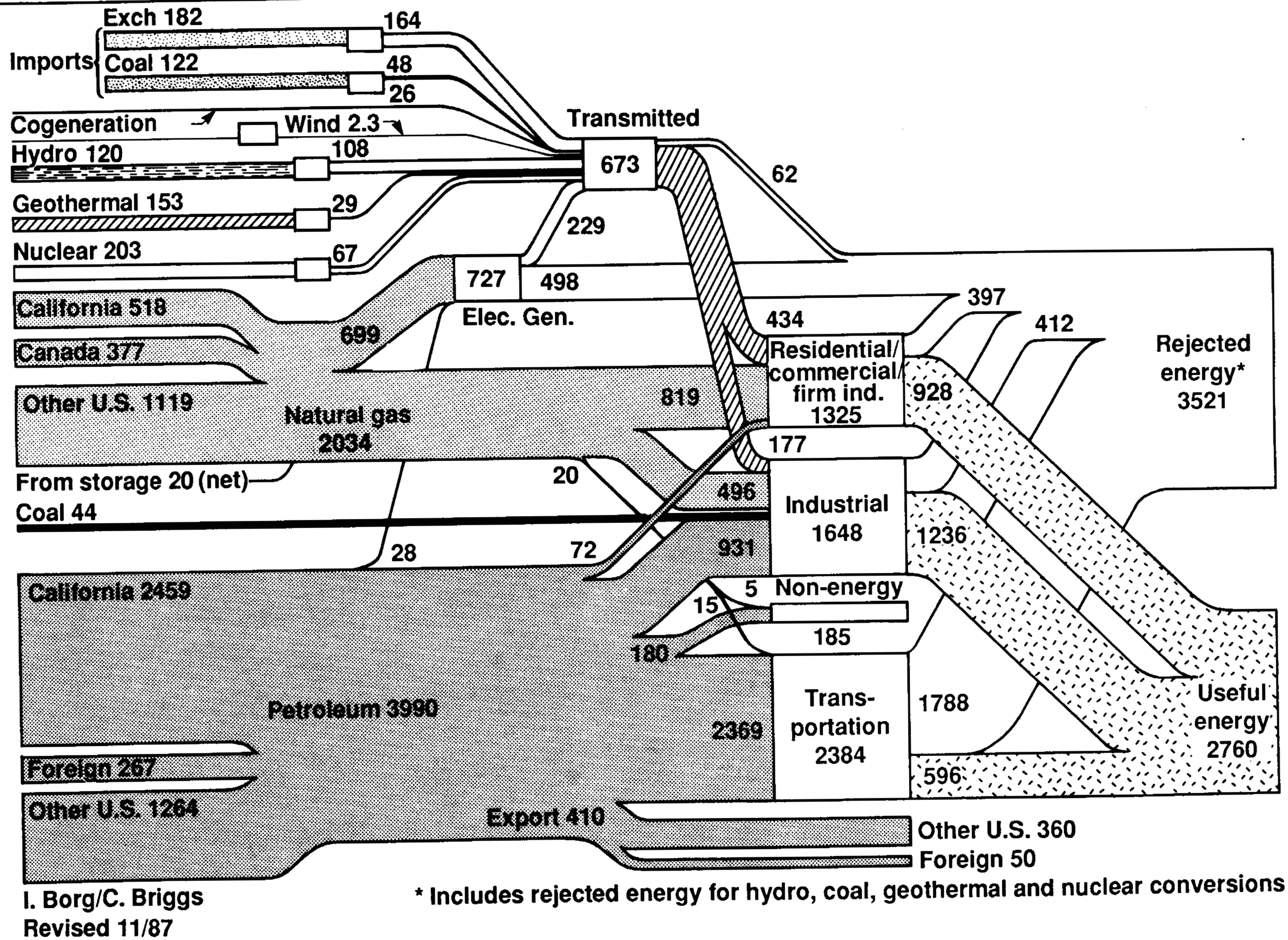


I. Borg/C. Briggs

* Includes rejected energy for hydro, coal, geothermal and nuclear conversions

Figure 1

CALIFORNIA ENERGY FLOW - 1985
TOTAL CONSUMPTION 6400 $\times 10^{12}$ Btu



* Includes rejected energy for hydro, coal, geothermal and nuclear conversions

Figure 2

U.S. Energy Flow — 1986
Net Primary Resource Consumption 74 Quads

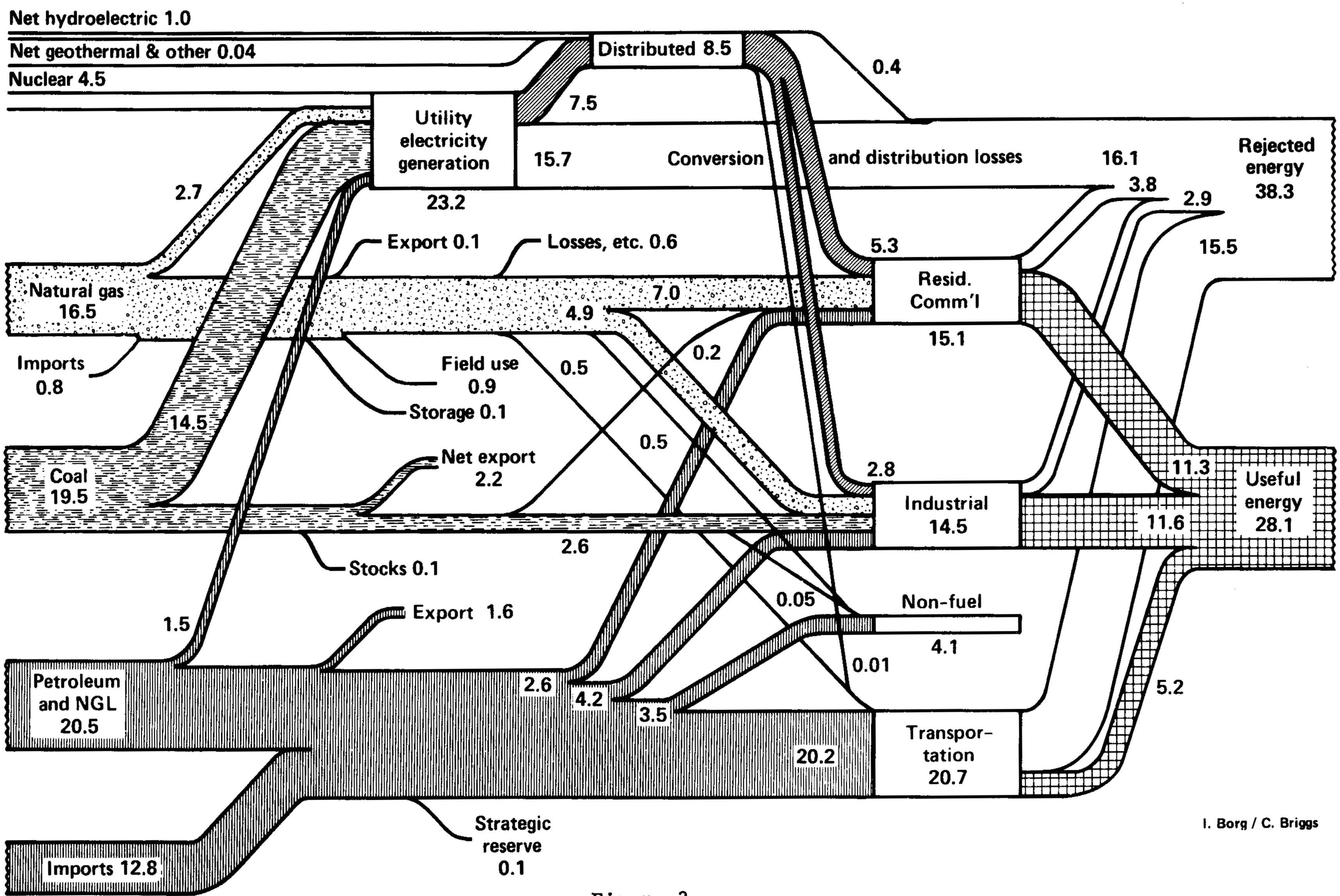


Figure 3

Table 1

Weather Comparison
1958 – 1986
Annual Heating Degree Days

	San Francisco Federal Office Building	Los Angeles Civic Center	San Diego Lindbergh Field
1958	2332	849	805
1967	2978	1040	1380
1968	2942	850	1052
1969	3066	941	1137
1970	3006	941	1137
1971	3468	1424	1657
1972	3240	918	1166
1973	3161	1066	1137
1974	3182	1084	1123
1975	3313	1548	1416
1976	2665	1128	793
1977	2888	911	747
1978	2599	1208	736
1979	2545	1160	902
1980	2799	597	590
1981	2819	506	573
1982	3195	975	913
1983	2386	602	623
1984	2648*	704	713
1985	2486	921	1079
1986	1842	473	843
Normal 1951–80	3071	1204	1284

*CA. Mission Dolores – same historical data as for Federal Office Building
Source: Local Climatological Data for San Francisco, Los Angeles and San Diego.

Table 2

California Transportation End Use

(in 10^{12} Btu)

	1980	1981	1982	1983	1984	1985	1986
Net gasoline	1375	1384	1345	1418	1413	1445	1543
Net aviation fuel	346	335	298	318	348	379	392
Taxable diesel fuel–public highways	160	166	161	168	201	207	218
Rail diesel	43	46	42	41	27	31	31
Net bunkering fuel	430	412	346	316	390	274	267
Military	32	42	36	35	40	33	35
Natural gas (pipeline fuel)	n.a.	n.a.	n.a.	n.a.	n.a.	15	13
Total	2386	2385	2228	2296	2464	2354	2499

n.a.: not available

Total natural gas use was not only effected by the mild weather but also by a the shift to other electrical generating power sources. The result was a large decrease (18.5%) in the use of natural gas, which brought usage to pre-1977 levels (Table 3). Total transmitted electricity for the year increased 3.5% from the previous year. All non-fossil fueled electrical power sources increased output – nuclear, geothermal, hydro power, and windpower – by impressive percentages. In addition, self-generated power and cogenerated electric power sold to the utilities continued to increase and displace electricity normally generated by the utilities themselves. Self-generating facilities are known to be increasing especially in heavy industries; however their contribution to the state's energy picture is difficult to assess accurately. Self-generation has no specific expression in Figures 1 and 2. In the case of cogeneration, amounts of electricity sold to the utilities are a matter of record and appear in Figure 1 as contributors to the amount of transmitted electricity. Fuels used for both self-generation and cogeneration, chiefly natural gas, are included in totals shown for the industrial sector.*

---

* Power from cogenerators shown in Figures 1 and 2 as inputs to total transmitted electricity appear without a box (representing the conversion process) that ordinarily would appear between the energy content of the fuel and the energy content of the final product. Conversion losses associated with both self-generation and cogeneration of electricity are included in "rejected energy" from the industrial end-use sector.

Table 3

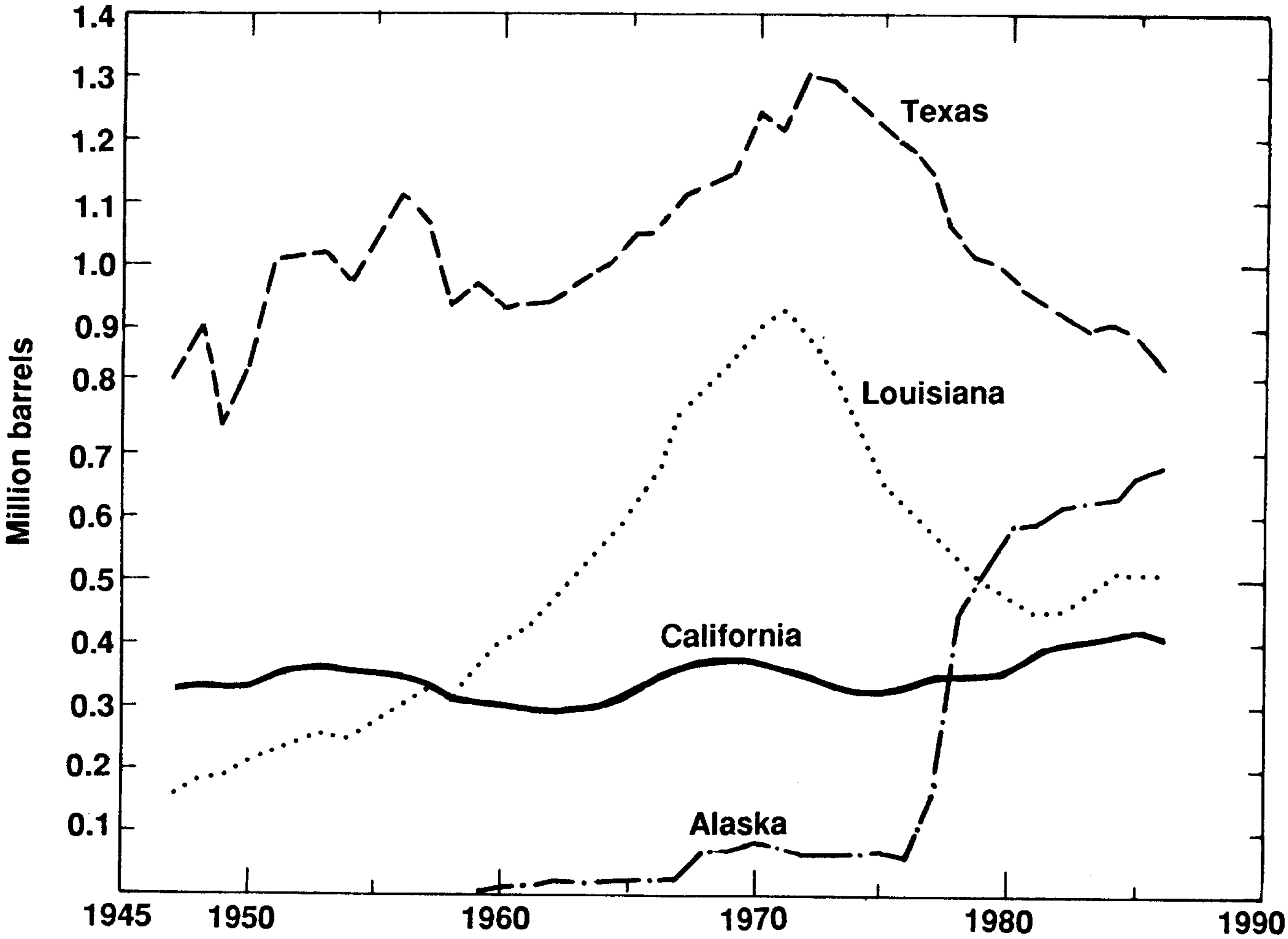
Comparison of Annual Energy Use in California

(in 10^{12} Btu)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Natural Gas	1831	1724	1971	1910	2010	1893	1769	1865	2034	1657
Crude Oil (net)	3720	3781	3967	3834	3650	3327	3329	3477	3580	3601
Transmitted Electricity	574	597	617	622	620	642	622	700	673	697
Residential/Commercial/ Firm industrial	1253	1321	1398	1334	1370	1225	1268	1176	1325	1287
Industrial	1248	1088	1216	1294	1400	1570	1395	1493	1648	1443
Non-energy	221	239	304	298	165	158	183	185	208	203
Transportation	2199	2438	2478	2471	2430	2265	2313	2464	2384	2499
Total Energy Consumption†	6000	6050	6500	6400	6300	6000	5900	6200	6400	6300

† Total is not sum of above figures because of rounding and inclusion of losses associated with conversion to electrical energy.

Until 1957 California was the second largest oil producer in the nation. It fell from the third ranked position in 1978 with the opening of the Alaskan pipeline the previous year. The state has remained fourth in the intervening years (Figure 4).



Source: Petroleum Supply Annual DOE/EIA

Figure 4. Historical record of largest oil-producing states

Oil production fell in 1986 for the first time since 1978. Forty percent of the decline was due to production cut-backs at the Naval Petroleum Reserve No. 1 at Elk Hills at the order the Department of Energy. The cut-backs came in response to concerns that the production rates were detrimental to maximum recovery of oil in the field over its lifetime and that the sales price for the oil which is determined by bidding was below market value.

The remainder of the decline reflects curtailed production as a consequence of the drop in crude oil prices from $20 at the beginning of the year to $10 per barrel at year's end.[8] Enhanced oil recovery accounted for 63% of total production in the state. Steam and water flooding made up 72% and 27% respectively of all EOR projects.[8] Natural gas production fell 6% notably in onshore fields not associated with oil production. The decline was the first since 1979.

There was considerable protest against the scheduled leasing of the outer continental shelf (OCS) beyond the 3 nautical mile limit in Northern and Central California. The last drilling offshore in Northern and Central California followed OCS sale P-1 in 1963 (Table 4). Twenty exploratory wells were drilled and ultimately plugged and the leases relinquished although hydrocarbon "shows" were reported in most wells. In the interim crude oil prices have increased dramatically, which has revived interest in the area. In response to earlier public objections by Californians, tracts in Northern and Central California were deleted from OCS Sale 53 (1981) and OCS Sale 73 (1983). Tentatively leasing is scheduled in Northern California (OCS Sale 91) for February 1989 and in Central California (OCS Sale 119) for November 1990. Environmentally sensitive areas that will not be included in the federal offering include the Cape Mendocino, the entrances to San Francisco and Monterey Bay, Point Reyes, the Farallon Islands and the Cordell Banks.

Table 4.

OCS Federal Lease Sales – Northern and Central California

Sale No.	Year	Area	Tracts Offered/ Leased	Number Exploratory Wells/ Discoveries	Production to Jan 86 (thousands bbl)
P1	1963	Eel River, Point Arena, Bodega, La Honda, Uno Nuevo, Santa Maria Basin	129/57*	20/0	0
P2	1964	Oregon and Washington	196/101*	12/0	0
53	1981	Santa Maria Basin (N. Calif. tracts withdrawn by Sec. Watt)	111/60	52/20	0
RS-2	1982	Santa Maria Basin (reoffering of OCS Sale 53 tracts)	27/10	0	0
73	1983	Santa Maria Basin (N. Calif. and all tracts N. of Morro Bay withdrawn by Congress)	137/8	0	0
91	1989	Eel River, Point Arena, Bodega, etc.			
119	1990	Central California			

*All leases relinquished.

Source: Pacific Summary Report, Dept. of Interior OCS Report, MMS 86-0060, May 86

Northern and Central California are not believed to contain large amounts of oil compared to traditional OCS areas such as the Gulf of Mexico (Table 5). Interest remains high in Southern California waters that have seen numerous sales over the years (Table 6).

Table 5

Undiscovered Economically Recoverable OCS Resources

Area	Mean Oil Billion bbl	Mean Gas Trillion c.f.	Probability
Alaska	3.33	6.90	
Atlantic	0.66	12.32	
Gulf of Mexico	6.03	59.64	
Pacific	2.19	4.70	
Northern California	0.25	1.12	0.60
Central California	0.36	0.51	0.65
Southern California	1.54	2.42	1.0
Washington & Oregon	0.04	0.65	0.20
Total Offshore	12.21	83.56	

Source: Outer Continental Shelf Oil and Gas Leasing/Production Program, U.S. Department of Interior, OCS Report MMS 87-0047, March 1987.

Table 6

OCS Federal Lease Sales - Southern California

Sale Number	Year	Tracts Offered/ Leased	No. of Exploratory Wells	No. of Development Wells	Production to Jan 87 (thousands bbl)
P3	1966	1/1	6	93	47
P4	1968	110/71	140	374	272
35	1975	231/56	41	99	20
48	1979	148/54	31	0	0
68	1982	140/29	8	0	0
80	1984	657/23	0	0	0
95	1989	---			
138	1992	---			

Source: Pacific Summary Report, U.S. Department of Interior, OCS Report MMS 86-0060, May 86.

NATURAL GAS SUPPLY

What has been described as the "gas bubble" in the U.S. has guaranteed more than ample natural gas supply to the state. In 1986 California received 49 percent of supply from the Southwest, 20 percent from Canada, 1 percent from the Rocky Mountains and 29 percent from in-state production. Use of natural gas in the state increased again in 1986 and will continue to grow as more cogeneration plants fueled with natural gas are built. Steam used in EOR projects is currently generated by burning oil produced at the sites; however declining oil production will foster use of alternative fuels. Cogeneration at EOR sites is an attractive option, and in most instances natural gas will be the chosen fuel.

With the decontrol of natural gas prices in 1985 the Federal Energy Regulatory Agency (FERC) took steps to encourage competition not only between producers but between pipeline companies as well. The resulting regulations have proven confusing to consumers, suppliers and the California Public Utilities Commission (CPUC) alike.

In response to FERC regulations the CPUC developed a new set of rates based on whether the customer was a "core" customer, i.e. a residential or commercial customer or a "non-core" customer, i.e. an industrial gas user who used 25 Bcf/year and had a fuel-switching capability. "Non-core" customers such as EOR operators may buy gas from anywhere, and this has encouraged new interstate pipeline proposals to bring new gas supplies from the southwest. The state's utilities claim that they can supply the EOR market without construction of additional pipelines. It is thus possible that large natural gas consumers can negotiate for the purchase of out-of-state gas and turn to the utilities for its transportation. This would be an added complexity to industrial rate schedules and the utilities' bookkeeping. They would have to keep track of volumes they transport and the points of receipt and points of delivery. In the event that the out-of-state supply to the large California customer is curtailed or contracts are not renewed, it is not clear that the state's gas utilities would be able to meet the added demand. Exactly how rates for both "core" and "non-core" customers of several sorts will be set in order to meet the utilities' fixed costs will remain uncertain until the industrial gas users individually make commitments with suppliers and decisions are handed down on the proposed interstate pipelines. It is almost certain that loss of many of the utilities' traditional industrial customers would lead to increases in the price of natural gas to "core" customers.

ELECTRIC POWER

Source of Supply

By a large margin the principal source of electrical power to the state is imported power (Table 7). Purchases are principally from the Western Area Power Administration that is most importantly supplied by power from Hoover Dam and the Bonneville Power Administration (Bonneville Dam). Additional imports come from out-of-state coal fired facilities that are partially owned by California utilities.

Natural gas is the most important fossil fuel used for electrical generation, but its use fell markedly (Table 3) in 1986. Oil is used primarily as a peaking fuel and plays a small role in utility power generation. Many small self-generators use oil and natural gas; however the amount is not a matter of record nor included in Table 7.

Table 7

Sources of California Utilities' Electricity – 1986

Source	Net electrical energy (trillion Btu)	
Imports		
Out-of-state coal facilities	60	
Purchases	174	
Total		234
Fossil fuels		
Natural Gas	140	
Oil	10	
Total		150
Nuclear power		90
Hydropower		142
Geothermal power		35
Windpower		4
Cogeneration		42
TOTAL		697

Cogeneration and the Impending Power Surplus

The California Energy Commission forecasts a 50,000 MW demand in the state by 1990 and a 55,000 MW "supply". In an effort to forestall the expected 5000 MW surplus in electrical power by the end of the decade, California's utilities have sought redress from state and federal regulatory agencies as well as from the U.S. Supreme Court. The unneeded power comes principally from independent producers (wind, solar, geothermal operators and cogenerators) that is sold to the utilities under the Public Utilities Regulatory Policies Act of 1978 (PURPA) at rates determined by "avoided cost", i.e. the cost of power if the utility were to build additional power producing plant for its own use. Under PURPA the utilities are required to buy the power from the independent producers. Apart from the anticipated surplus, many of the long term contracts signed by the utilities with the independent producers were negotiated in the early eighties when oil and gas prices were at a peak and when virtually all forecasts predicted much higher prices in the ensuing decade. Thus contracts signed involved payments of 6 to 9 cents per kwh whereas the "avoided cost" in 1986 was near 3 cents per kwh. If the amount of power offered to the utilities had proven to be small, the added cost to the utilities would have been relatively insignificant. But at the end of 1986 Pacific Gas and Electric Company, the nation's largest utility that services northern California, had 9300 MW of independent power under contract with 2000 MW[9] on line compared to a peak demand equivalent to 15,439 MW and utility generating capacity of 15,182 MW. All totaled approximately 4000 MW of power from independents was under contract to the state's utilities in 1986 in addition to the state's operable generating capacity of 45,000 MW.

Whether all the contracted power will become a reality is not certain; further much of the alternative power under contract is from intermittent sources so that the nominal electrical capacity belies the actual amount of electricity that will be sold to the utilities. Future applications for certification of cogeneration facilities may not fare as well as they have in the past. The California Energy Commission has exclusive authority to certify all sites and related facilities for thermal electric power plants 50 MW and over. Before an application can be approved, the commission must determine that the project is needed to meet its demand forecast. In 1986 the CEC denied certification of a 246 MW facility at the C & H sugar refinery in Crocket on the grounds that additional baseload electrical capacity was not needed in Northern California.[10] Nonetheless Pacific Gas and Electric Co. and Southern California Edison, the two largest electrical utilities in California, estimate that by 1991 20% and 23% of their demand respectively will be met by independent generators.[11,12]

The situation has many ironic aspects:

- o The high prices paid by the utilities for the power purchased under PURPA are passed onto the consumer which puts the state consumer groups, who backed PURPA as an alternative to building large costly base load plants, in the position of sanctioning what has proved to be the highest priced power available. Surplus power in the Pacific Northwest that is available for import stood at 5000 MW in 1986[11]; its cost is about 1 cent per kWh.

- o Of the new sources the largest and fastest growing in the state is power from cogeneration associated with oil production and refining and food processing. In almost all instances the fuel used is either oil or gas, the fuels whose use was to be discouraged by PURPA and the Fuel Use Act of 1978, which essentially precludes the use of oil or gas for new generating capacity by the utilities.

- o The "small is beautiful" and "limits to growth" philosophies that flourished at the time the federal legislation was passed have in the end given impetus to the development of more efficient conventional power producing equipment (gas turbines and combined cycle facilities) which are being sold to the large cogenerators. It has been essentially business-as-usual for the large firms who have historically supplied generating equipment to the utilities.

Nuclear Power

Nuclear power plays a small role in the state's sources of electricity. There are six plants with a combined generating capacity of 5.7 GWe (net) out of approximately 45 GWe total capacity. In addition, Southern California Edison Co. has a partial interest in the

Palo Verde nuclear plants in Arizona. The total generating capacity in California is difficult to know precisely because of the rapid growth of both self-generation and cogeneration in the private sector.

Except for Rancho Seco, a 913 MWe nuclear plant near Sacramento, all nuclear plants were operational in 1986. Rancho Seco was down for repairs following a radiation leak detected in December 1985. Diablo Canyon 1 (1.1 GWe) nuclear plant set a national operational record during its first year of operation ending in May of 1986. Diablo Canyon 2 (1.1 GWe), which began commercial operation in March of 1986, was following a similar pattern at year-end.

Noteworthy during 1986 were the arguments and decisions concerning how much of the costs of the nuclear plants would be allowed to be recovered in the utilities rate base. The Public Utility Commission disallowed 8% of the $4.5 billion cost of San Onofre 2 and 3 (2.2 GWe) completed in 1983 and 1985. Arguments on Diablo Canyon continued into 1987. Staff of the CPUC are expected to recommend that an even smaller portion of the costs be borne by ratepayers – perhaps as small as 20% of the $5.8 billion investment.

<u>Renewable Sources of Electricity</u>

Geothermal energy

Geothermal energy continued to be utilized in the state with almost 2000 MW of electrical capacity on line. Of the total the Geysers Geothermal Field in northern California contributed the largest share– 1773 MW.[8] Drilling and plant construction was on-going at a number of sites throughout the state (The Salton Sea, Coso dome near China Lake, Long Valley and Casa Diablo in Mono County, East Mesa and Heber, east of El

Centro, and Wendel in Lassen County); at least 135 MW of electrical capacity is either under construction or in the planning stage. In addition, the largest district heating system in the nation was inaugurated in May of 1986 by the City of San Bernadino. The hot water from the San Bernadino Geothermal resource area will be used by City Hall, the local sewage plant and the Ramada Inn.

Windpower

California has the largest windfarms in the world, which in large part is due to federal and state incentives for development of alternative forms of energy. 1986 was the last year that the young industry enjoyed generous state 25% tax credits. The federal credits expired January 1, 1986. As can be seen from Table 8, the number of turbines and their combined capacity continued to grow albeit at less than historical rates. As an alternative form of energy, new contracts for purchase of windpower by the utilities are based on "avoided costs" established by PURPA. From the beginning to the end of 1986 in California the average seasonal price paid fell from 6.3 to 2.7 cents per kWh. The all-time high was 7.45 cents per kWh in October 1984. The drop reflects the fall in the price of conventional fuels used for power production. According to Thomas O. Gray, director of the American Wind Energy Association in Washington, the costs of making and operating windmills is 12 to 20 cents per kWh.[13] Although improvements in design and manufacturing costs are to be expected, at this juncture the industry does not appear to be profitable without support.

Table 8

Windpower installations in California as of January 1

Location	Capacity (MWe)			Number of turbines		
	1985	1986	1987	1985	1986	1987
Altamont Pass area, 45 miles east of San Francisco	318	479	584	3900	5154	6219
San Gorgonio Pass, Riverside Co. near Palm Springs	150	190	295	2450	2801	4155
Tehachapi Pass, Kern Co.	132	186	355	1950	2544	4175
Mojave Desert, Kern Co.	7	(n.a.)	0	150	(n.a.)	0
Boulevard, San Diego Co.	4	1.25	0.8	16	51	36
Carquinez Strait, Solano Co.	3	.63	0	10	6	0
Pacheco Pass, San Benito Co.	0	(n.a.)	0.5	0	(n.a.)	20
Salinas Valley	0	0.1	0.16	0	4	4
TOTAL	609	857	1235	8476	10560	14609

n.a. = not available

Source: California Energy Commission, Results from the Wind Project Performance Reporting, System 4th Q (1984, 1985, 1986).

New development is going ahead under undeveloped power purchase agreements that were signed with California utilities and Standard Offer 4 contracts and development rights signed with the California Public Utilities Commission in the early 1980s. The CPUC 20 to 30 year contracts were designed to encourage congeneration and small power development and were tied to projected "avoided costs" based on $60 per barrel oil by 1990.[14]

The California Energy Commission has made a concerted effort to promote methanol as a transportation fuel for almost a decade. The impetus came from the state's air pollution problems which are attributed in large part to hydrocarbon emissions from vehicles. The State of California operates 550 methanol-fueled vehicles as part of a demonstration project. Under a state agreement with a major oil company there are approximately 23 methanol fueling stations and another six private stations servicing the Bank of America's 275 vehicle fleet. The Bank turned to methanol in 1979 in response to fuel shortages. Approximately 12 percent of the Bank's automobiles and light weight trucks are methanol-fueled. Both the Bank's and the State's experience with the modified gasoline engines has been excellent, but both establishments would prefer to purchase methanol automobiles rather than retrofitting existing vehicles for methanol use. Typically gas tanks, carburetors and gaskets are replaced to accommodate methanol use.

In addition several methanol-fueled buses are under trial by the Golden Gate Transit District. To date they have performed satisfactorily, but there have been some concerns about fuel economy when comparisons are made with gasoline and diesel counterparts in the fleet.[15] Transit authorities in Riverside and Los Angeles are in the process of considering or acquiring methanol buses for trials.

Methanol as a blending fuel has many advantages such as its octane-improving quality; however its use in California is limited by emission standards. When blended with gasoline, alcohols cause an increase in hydrocarbon emissions.[16] Exemptions to vapor control regulations have been granted by state and federal agencies for gasoline-ethanol blends but do not extend to gasoline-methanol.

Appendix A

Data Sources for California Energy Supply (1986)

Production	Source
Crude Oil including Federal Offshore and Lease Condensate	Ref. 8
Associated and Nonassociated Natural Gas	Ref. 8
Electric Utility Fuel Data	Ref. 17, Table 14, Consumption by Census Division and State
Electrical Generation (hydro, nuclear, oil, gas, geothermal)	Ref. 17, Table 6, Net Generation by Census Division and State
Wind	Ref. 18
Cogeneration	Ref. 19, Electric Utilities Energy Transactions
Imports	
Natural Gas Foreign and Domestic	Ref. 19, Natural Gas Utility Sources of Supply
Crude Oil Foreign and Domestic	Ref. 20, Table 1, California Petroleum Summary
Oil Products Foreign and Domestic	Ref. 20, Fourth Quarter, Table A-1, California Petroleum Fuels Market Activity
Coal	Ref. 21, Table 24, Coal Consumption by Census Division and State
Electrical Power	
Net Exchange	Ref. 19, Electric Utilities Energy Transactions
Coal	Ref. 19, Electric Utilities Generation Resources and Electric Utility Fuel Data
Exports	
Oil Products Foreign and Domestic (not including bunkering fuel supplied at California ports)	Ref. 20, Fourth Quarter, Table A-1, ibid.

Appendix B

Data Sources for California End Uses (1985)

Net Storage and Field Use	
Natural Gas	Ref. 19, Natural Gas Utility Disposition of Supply
Transportation	
Crude Oil	
Gasoline, aviation and jet fuels	Ref. 20, Fourth Quarter, Table A-1, ibid. (CA supplied)
Taxable Diesel Fuel (i.e. for public highways)	Ref. 22, Table A-11, Sales for Transportation Use: Distillate Fuel Oil and Residual Fuel Oil, 1986
Vessel Bunkering (includes international bunkering)	Ref. 22, Table A-11, ibid.
Rail Diesel	Ref. 22, Table A-4, Sales of Distillate Fuel Oil by End Use, 1985 and 1986
Military Use	Ref. 22, Table A-12, Sales for Military Use, etc.
Natural Gas	
Pipeline fuel	Ref. 23, Table 13
Industrial, Government, Agriculture, etc	
Natural Gas	By difference
Coal	Ref. 21, Table 24, ibid.
Electricity	Ref. 17, Table 45, Sales of Electricity to Ultimate Consumers by Census Division and State 1982-1986
Crude Oil	By difference
Non Energy Applications	
Crude Oil and LPG	
Asphalt	Ref. 24
Petrochemical feedstock	Ref. 25, Table 8, PAD District V, Supply and Disposition of Crude Oil and Petroleum Products, 1986
Waxes, lubricating oils, medicinal uses, cleaning	Ref. 20, Table A-5, California Refinery Activity by Type and Area
Natural Gas	
Fertilizer	Ref. 26
Residential and Small Commercial	
Natural Gas	Ref. 27, Table 22, Natural Gas Deliveries to Residential Consumers by State. Table 23, Natural Gas Deliveries to Commercial Consumers by State
Crude Oil and Other Oils (kerosene, residual, and distillate)	Ref. 22, Tables A-4, A-5, A-6 (A-6, Sales of Kerosene by End Use)
LPG	Ref. 25, Table 8, ibid.
Miscellaneous "off highway" Diesel	Ref. 22, Table A-4, ibid.
Electricity	Ref. 17, Table 45, ibid.

Appendix C

Conversion Units

Energy Source	Conversion factor, 10^6 Btu
Electricity	3.415 per MW.h
Coal	22.6 per short ton
Natural Gas	1.05 per Mcf
LPG	4.01 per barrel
Crude Oil	5.80 per barrel
Fuel Oil	
Residual	6.287 per barrel
Distillate, including diesel	5.825 per barrel
Gasoline and Aviation Fuel	5.248 per barrel
Kerosene	5.67 per barrel
Asphalt	6.636 per barrel
Road Oil	6.636 per barrel
Synthetic Rubber and Miscellaneous	
LPG Products	4.01 per barrel

Assumed Conversion Efficiencies of Primary Energy Supply

Electric power generation	
Hydro power	90%
Coal	30%
Geothermal	18%
Oil and Gas	33%
Uranium	32%
Transportation Use	25%
Residential/Commercial Use	70%
Industrial Use	75%

REFERENCES

1. E. Behrin and R. Cooper, California Energy Outlook, Lawrence Livermore Laboratory Report, UCRL-51966, Rev. 1 (1976).

2. I. Y. Borg, California Energy Flow in 1976, Lawrence Livermore Laboratory Report, UCRL-52451 (1978).

3. I. Y. Borg, California Energy Flow in 1977, Lawrence Livermore Laboratory Report, UCID-18221 (1979).

4. C. Briggs and I. Y. Borg, California Energy Flow in 1978, Lawrence Livermore Laboratory Report, UCID-18760 (1980).

5. C. Briggs and I. Y. Borg, California Energy Flow in 1979,1980, 1981, 1982, 1983, and 1985, Lawrence Livermore Laboratory Reports, UCID-18991 (1981), 18991-80 (1982), 18991-81 (1983), 18991-82 (1983), 18991-83 (1984), and 18991-85 (1986).

6. I. Y. Borg and C.K. Briggs, "California's Energy Supply and Demand in 1984", Annual Review of Energy 11. 209-28 (1986).

7. The Tri-Valley Herald, p. 5 (February 5, 1987).

8. 72nd Annual Report of the State Oil and Gas Supervisor - 1986, California Department of Conservation Publ. No. PR06, (1987).

9. D. Wamsted, "Supreme Court lets stand California's avoided costs rule," The Energy Daily 15, p. 1, (October 6, 1987).

10. News and Comment, California Energy Commission Quarterly Newsletter, No. 20, (Fall 1986).

11. D. Woutat, "State's utilities suffer a costly power suplus; customers pay," Los Angeles Times Pt III, p. 17, (September 7, 1987).

12. 1986 Financial and Statistical Report, Pacific Gas and Electric Company, San Francicco, CA (1987).

13. D. Struck, "Wind power struggles to find its place," The Sun, p. A1 (December 26, 1985).

14. R. McCormack, "Survival of the fittest: reckoning ahead for wind energy," The Energy Daily 14, p. 2 (May 1, 1986).

15. Status of methanol vehicle development, U.S. General Accounting Office Report GAO//RCED-87-10BR, p. 69, Washington, D.C. (October, 1986).

16. Energy Development, California Energy Commission, Sacramento, CA. p. 42 (June 1986).

17. Electric Power Annual 1986, DOE/EIA-0348 (86) (September 1987).

18. Results from The Wind Project Performance Reporting System, 4th Q 1986, California Energy Commission, P500-87-018 (October 1987).

19. Energy Watch, Quarterly Supplements, California Energy Commission (October, November, December 1986, March/April 1987).

20. Quarterly Oil Report, California Energy Commission (June, September, December 1986 (March 1987).

21. Quarterly Coal Report, DOE/EIA–0121 (86/4Q) (April 1987).

22. Petroleum Marketing Monthly, DOE/EIA–0380 (87/07), (October 1987).

23. Natural Gas Annual 1986, Vol I, DOE–EIA–0131 (86) 1 (November 1987).

24. Asphalt Usage in the United States and Canada 1986, Asphalt Institute, College Park, MD (May 1987).

25. Petroleum Supply Annual, DOE/EIA–0340 (86)/1 (May 1987).

26. Personal Communication, Ken Northcutt, Unocal Chemicals, Division of Unocal Oil (November 6, 1987).

27. Natural Gas Monthly, DOE–EIA–0130 (87/01) (March 1987)

7922F

Technical Information Department • Lawrence Livermore National Laboratory
University of California • Livermore, California 94550